**Frequently Asked Questions**
**Revision Date: November 20, 2001**

## Integrity Management Rule Basics

**What are the Office of Pipeline Safety's objectives for the Integrity Management rule?**
The integrity management rule has four primary objectives:
- accelerating the integrity assessment of pipelines in High Consequence Areas
- improving operator integrity management systems
- improving government's role in reviewing the adequacy of integrity programs and plans, and
- providing increased public assurance in pipeline safety.

**Who must comply with the rule?**
This initial rule applies to operators who own or operate 500 or more total miles of hazardous liquid pipelines jurisdictional to 49 CFR Part 195. These 500 miles need not be contiguous. Every pipeline segment that can affect an HCA, regardless of length, is covered by the rule if the operator has a total of 500 or more miles. A rule covering hazardous liquid pipeline operators having less than 500 miles of line will be issued shortly. Rules covering natural gas pipeline operators are planned for 2002.

**Is integrity management simply inspection of pipe condition?**
No. While assessing the pipe condition and correcting identified anomalies is an important part of the rule, there are other important requirements. Operators must develop improved management and analysis processes that integrate all available integrity-related data and information, and assess the risks associated with segments that can affect HCAs. Furthermore, operators must implement additional risk control measures if needed to protect HCAs. Examples of these additional measures include: enhanced damage prevention programs, reduced inspection intervals, corrosion control program improvements, leak detection system enhancements, installation of Emergency Flow Restricting Devices (EFRDs), and emergency preparedness improvements.

**What is a high consequence area (HCA)?**
High consequence areas are defined in the rule as either:
- High population areas, defined by the Census Bureau as urbanized areas,
- Other populated areas, defined by the Census Bureau as places that contain a concentrated population,
- Unusually sensitive areas, or
- Commercially navigable waterways

Unusually sensitive areas are defined in the new Part 195.6 as drinking water or ecological resource areas that are unusually sensitive to environmental damage from a hazardous liquid pipeline release. OPS will apply this definition to identify HCAs and will make available maps that depict them. Operators are also responsible for independently evaluating information about the area around their pipeline to identify areas that become HCAs.

**When does the rule go into effect?**
The rule for hazardous liquid pipeline operators having 500 or more miles of pipeline became effective May 29, 2001. The rule requires that operators identify segments of their pipeline that could affect High Consequence Areas by December 31, 2001. Operators must also prepare their Baseline Assessment Plans, and develop their Integrity Management Program Framework by March 31, 2002.

## Rule Applicability

**Does the rule apply to more than line pipe?**
Yes. The continual evaluation and information analysis requirements of the rule apply to pipelines as defined in 49 CFR 195.2. This includes, but is not limited to, line pipe, valves and other appurtenances connected to line pipe, metering and delivery stations, pump stations, and breakout tanks. The baseline integrity assessments and periodic re-assessments apply only to line pipe.

**Does the rule apply to offshore pipelines?**
Yes, but the rule does not apply to all offshore pipelines. The rule applies to those segments of offshore pipelines that could affect HCAs, principally commercially navigable waterways and unusually sensitive areas.

**If an operator has ERW pipe and has already taken the 20% pressure reduction according to 195, Subpart E, is this pipeline system exempt from the HCA rule?**
No. The requirements of 195.452 still apply.

**What is meant by "operator who owns or operates a total of 500 or more miles of pipeline" in 195.452 (a)? For example, if an operator who operates more than 500 miles of pipeline also owns a small percentage of a small pipeline (less than 500 miles) that is operated by a different organization - does that smaller operator have to comply with the 500 mile or more rule - even if its O&M manual, management processes, etc. are totally separate from the large operator?**
The current rule applies to operators who own or operate a total of 500 or more miles of pipeline. This means that if an operator also is part owner of another pipeline operating company, the mileage of that other company is included in determining whether or not the 500 mile criteria is met. If the total pipeline mileage is equal to or greater than 500 miles, then the requirements of the current rule apply to both companies' pipeline systems - even if they have totally distinct O&M manuals, etc.

**If the operator of a small pipeline system (i.e. less than 500 miles) is partially owned by an operator who operates more than 500 miles of pipeline, who is responsible for preparing the Baseline Assessment Plan and complying with the provisions of this rule - the operator, or the company that is part owner?**
The operator is required to comply with OPS regulations, and thus is responsible for preparing a Baseline Assessment Plan that meets all of the requirements in 195.452 (c). Operators may use outside resources, including adopting management plans prepared by parent companies, but that does not relieve the operator of responsibility for having an acceptable plan.

**If a company acquires additional pipeline in late 2001 that takes its total mileage over 500, are they covered by the rule? Are the deadlines the same?**
A company acquiring additional pipeline mileage that takes its total over 500 miles is covered by the rule. There are no different deadlines for such a situation.

**If a pipeline transports both gas and liquids (e.g., some off shore lines), does the hazardous liquid integrity management rule apply, or will the forthcoming gas integrity management rule apply?**
Lines that transport both liquids and gas must meet requirements applicable to both. In practice, this means that the more stringent requirement must be met. Such lines must meet 195.452. When an integrity management rule is promulgated for gas lines, any requirements in that rule that are more stringent would apply.

## Segment Identification

**When must pipeline segments subject to the rule be identified?**
Pipeline segments that can affect an HCA must be identified by December 31, 2001.

**Many operators have pre-defined segments on their pipeline (e.g., the length of pipe between two pump stations is considered a segment). When OPS refers to segments that can impact an HCA in the rule, in what context is the term segment used?**
As used in the rule a segment that can impact an HCA refers to a continuous portion of a pipeline system in which the released commodity from a failure occurring anywhere between the two end points of the segment could migrate to and impact a HCA. The segment sizes should be defined by whether or not a spill could impact the HCA and not by pre-set definitions used by the operator.

**How will an operator determine if a pipeline can affect an HCA?**
Appendix C of the rule provides guidance on factors an operator should consider in determining whether a pipeline can affect an HCA. An example is provided in the Appendix. The factors are:

- Potential physical pathways between the pipeline and the high consequence area.
- Terrain surrounding the pipeline. An operator should consider the contour of the land profile and if it could allow the liquid from a release to enter a high consequence area. An operator can get this information from topographical maps such as U.S. Geological Survey quadrangle maps.
- Drainage systems such as small streams and other smaller waterways that could serve as a conduit to a high consequence area.
- Crossing of farm tile fields. An operator should consider the possibility of a spillage in the field following the drain tile into a waterway.
- Crossing of roadways with ditches along the side. The ditches could carry a spillage to a waterway.
- Potential natural forces inherent in the area (flood zones, earthquakes, subsidence areas, etc.)

- The nature and characteristics of the product the pipeline is transporting (refined products, crude oils, highly volatile liquids, etc.) Highly volatile liquids become gaseous when exposed to the atmosphere. A spillage could create a vapor cloud that could settle into the lower elevation of the ground profile.
- Physical support of the pipeline segment such as by a cable suspension bridge. An operator should look for stress indicators on the pipeline (strained supports, inadequate support at towers), atmospheric corrosion, vandalism, and other obvious signs of improper maintenance.
- Operating condition of pipeline (pressure, flow rate, etc.) Exposure of the pipeline to operating pressure exceeding established maximum operating pressure.
- The hydraulic gradient of pipeline.
- The diameter of pipeline, the potential release volume, and the distance between the isolation points.
- Response capability (time to respond, nature of response).

**What is acceptable methodology and criteria for determining whether a segment could affect an HCA? (For example what spill volume should be considered - Worst-case discharge? Most likely discharge? Most likely worst-case discharge?) Can an arbitrary safe distance be applied or must location specific dispersion analyses be performed? Is air dispersion modeling expected or is spill trajectory adequate?**
OPS expects each operator to develop a process for identifying what portions of its pipeline system could affect an HCA in the event of a failure. This process is a required Integrity Management program element per 195.452 (f). OPS does not intend to dictate how operators must make these determinations. OPS will look for sound engineering judgment with a reasonable amount of conservatism to account for uncertainties in the assumptions and calculation methods used in the analysis. Operators should be able to justify the assumptions used in making these determinations.
Companies that apply an arbitrary “safe distance” should justify how this distance was determined and provide convincing evidence that this “safe distance” is indeed bounding for all segments that could affect HCAs.
Air dispersion should be considered in instances where hazardous material could be transported by air (e.g., failures of HVL lines).

**Do operators need to perform detailed consequence analysis to determine the specific impacts on population or USAs?**
OPS expects that an operator will develop an understanding of the potential consequences of leaks and ruptures of its pipelines. The operator should be able to estimate the severity of releases in terms of volume of product released and transported to an HCA, and the population and environmental resources that can be affected by such a release. The operator should develop a sufficient understanding of the severity and impact of potential releases to determine the appropriate preventive and mitigative actions. This should include at least an understanding of the amount of hazardous material that could be released, the physical pathways and dispersion mechanisms by which the commodity can be transported to an HCA, and the amount of commodity that might actually reach the boundaries of the HCA.

**Performing technically rigorous, location-specific analysis to determine segment boundaries that can impact HCAs is time consuming and resource intensive. Operators with large systems may not be able to perform such analyses by December 31, 2001. Will operators be able to defer some or all of this analysis until a later date?**
The operator is responsible for identifying all pipeline segments where failures might impact HCAs by December 31, 2001. OPS recognizes that there are varying levels of technical rigor that can be applied to make this determination. Some operators, in order to meet the compliance deadline, may elect to rely on conservative, simplifying assumptions in making these calculations. As long as these assumptions provide assurance that segments that can affect HCAs have been identified, this approach is acceptable. However, these segment definitions must be used in developing the Baseline Assessment Plan, must be addressed by baseline assessments, and would be subject to the other provisions of the rule, such as the repair provisions in 195.452 (h). As part of refining its integrity management program, an operator could add more technical rigor and precision to the calculations, thereby reducing the size of segments that can affect HCAs. The refined definitions can only be implemented after baseline assessment of the “larger” segments has been performed, including any required repairs.

**How will HCAs be identified and communicated to the industry?**
OPS will apply the definition of an HCA and identify areas throughout the nation that meet it. These areas will be defined graphically, on maps, and will be available via the National Pipeline Mapping System. Operators may also identify new HCAs. Operators are required to analyze information about the areas in the vicinity of their pipelines. When those analyses identify areas which would meet the definition of an HCA (e.g., due to population expansion), the operator must include these new HCAs in its integrity management program.

**What are OPS expectations for operators to determine new or changed HCAs after the initial posting on the NPMS?**
Operators are expected to monitor conditions along their line. When they become aware of changes that create or change an HCA (e.g., population expands to encompass more of the area near the pipeline right-of-way), this information should

be factored into their integrity assessment planning, risk analysis, and consideration of the need for additional preventive and mitigative risk controls. Information on operator-identified HCAs need not be provided to OPS for mapping.

**When must newly-identified HCAs be included in the program?**
Over time, new HCAs may be identified as population distributions change, or new drinking water or ecological resource data becomes available. OPS will periodically update the HCA maps and make them available on the Internet for operator use. Operators may also identify new HCAs on their own by monitoring local population growth or through knowledge of environmental resources that becomes available to them. In either event, a newly-identified HCA must be incorporated into the integrity management program within one year of its identification. A baseline assessment for pipeline segments that could impact newly identified HCAs must be performed within five years of its identification.

**On what frequency or schedule will changes to the HCA maps on the NPMS be made? Will OPS announce or provide public notice of changes?**
OPS will update the population HCAs when the 2000 census data is provided by the Census Bureau. OPS currently intends to update the USA maps every five years. Changes to the commercially navigable water ways HCAs are expected to change infrequently. OPS will post information on its web site when updates to the HCA maps are posted. In addition, when major revisions are performed, such as for the periodic USA update, OPS will publish a Federal Register Notice to announce the availability of the newly revised maps.

**How will OPS track changes to HCA information over time? When data fields are changed, will operators be able to clearly distinguish the new information from the old in NPMS?**
OPS is currently using version numbers in naming HCA data layers to track changes over time. OPS is considering developing data layers that show only newly identified HCAs. A final decision on this approach will be made after the new 2000 census data for high population and other populated areas is obtained. This will allow users to distinguish between the old HCA boundary information and the newly posted data.

**If OPS does not complete the Unusually Sensitive Area (USA) mapping for some states by December 31, 2001, what responsibility does an operator have to identify segments that could impact USAs in those states? Similarly, for those states for which the USA mapping is not completed until late 2001 (e.g., final quarter CY2001), will OPS grant some relief from meeting the December 31, 2001 segment identification requirement to operators with pipelines in those states?**
To promote a national consistency in the identification of HCAs, OPS is in the process of mapping these locations on the National Pipeline Mapping System (NPMS). Currently, all of the population and commercially navigable water way HCAs have been mapped. USAs in states with more than 90% of the hazardous liquid pipeline miles have already been mapped. It is possible that the USAs may not be fully mapped for a small number of states by the end of 2001. Operators are responsible for identifying all pipeline segments that could impact HCAs in all states by December 31, 2001, regardless of whether all of the HCAs have been mapped on NPMS. For those few states in which USA maps are not available on NPMS, operators may use ecological and drinking water information used to prepare and maintain their spill response plans as well as other resources available to them to identify USAs.

**For those states in which USA maps are not posted until after December 31, 2001, how long does an operator have to incorporate this new information into its segment identification and assessment planning process?**
For the limited number of states where USA mapping may not be complete by December 31, 2001, operators are responsible for identifying USAs. Operators may use ecological and drinking water information used to prepare and maintain their spill response plans as well as other resources available to them to identify USAs. Once USAs are mapped for that State, an operator will have up to one year to incorporate newly-identified USAs in its Baseline Assessment Plan. OPS inspections will assess whether operators made a good faith effort to identify USAs in these limited instances, and enforcement action may be taken if it is determined they did not.

**If an operator desires location and other information on a specific ecological or drinking water USA to use in risk analysis and determination of potential pipeline release impacts, how can this information be obtained?**
Those operators who desire to make more accurate determinations of whether their system can impact a particular USA can obtain more specific information on the location of particular USAs from their drinking water providers and state heritage networks. Operators can obtain contact information for a particular USA by clicking on the USA on the NPMS. OPS will not act as an agent for purposes of gathering additional information.

**Since the USA data in the NPMS contains buffer zones around the actual drinking water or ecological resource, is it possible that an operator's evaluation to determine whether a spill could impact an HCA might show a release reaching a USA depicted on the NPMS map when in reality such a release might not actually reach the sensitive area?**
Yes. In mapping USAs in the NPMS, buffers were used to account for the inaccuracies of the species or drinking water location data. Thus it is possible that spills "just reaching the edge" of a USA boundary (for instance) might not actually

impact the drinking water or ecological resource. Those operators who desire to make more accurate determinations of whether their system can impact a particular USA can obtain more specific information on the location of particular USAs by contacting the entities that supplied the drinking water and ecological data to OPS. Operators can find contact information for these drinking water and ecological data suppliers by clicking on the USA in the NPMS.

**What mechanism is available for questioning or challenging HCA and USA identification once such identification has been posted on the National Pipeline Mapping System?**
HCAs and USAs have been defined in Part 195. These definitions were developed after considering significant public and industry input, and they are now final. OPS is using recognized organizations and data sources for mapping HCA information. Anyone having new information that they believe could affect the accuracy of the mapped HCAs (e.g., errors in data sources, or more recent data) should contact OPS.

**Must non-pipe elements of a pipeline system that can affect HCAs (e.g., stations and facilities) be identified by 12/31/01?**
Yes. While the assessment requirements of 49 CFR 195.452 are applicable to line pipe, all other requirements, including segment identification, are applicable to the entire pipeline system as defined in 49 CFR 195.2. OPS expects operators to understand which pump stations, terminals, and other facilities might also impact HCAs in the event of a failure.

**If an operator initially treats its entire system(s) as having the potential to affect an HCA to meet the 12/31/01 deadline for segment identification and then includes its entire system in its Baseline Assessment Plan, can they later refine this approach by defining only specific, smaller segments that can affect an HCA (e.g., when it comes time to make repairs after a tool run, or for the purposes of evaluating the need for EFRDs)?**
If an operator elects to treat its entire pipeline system(s) as having the capability to affect an HCA, then all other provisions of the rule apply to its entire pipeline system(s). For example, this means that the repair schedules established in 195.452 (h) must be applied to the entire pipeline system following the baseline integrity assessments.
However, declaring an entire pipeline system as having the capability of impacting an HCA does not relieve the operator from the responsibility to understand how failures on its system could impact HCAs. The rule requires that each operator's Integrity Management Program must include a process for identifying which segments could impact a high consequence area [195.452 (f) (1)]. Furthermore, as part of the required risk analysis 195.452 (g) and (i) (1), operators must determine the consequences of pipeline failures including impacts on HCAs. Hence, some understanding of those portions of the system where a spill could impact an HCA must be part of this risk analysis.
Operators who initially treat their entire system as having the capability to affect an HCA will be expected to conduct baseline assessments and to repair identified anomalies in accordance with 195.452 (h) on all of their pipeline. After completing this work, these operators may refine their definition of segment boundaries that can affect HCAs to focus their programs on the areas that can truly impact HCAs as determined by applying their segment identification process [195.452 (f) (1)].

## Baseline Assessment Plans

**What is an assessment?**
As used in the rule, assessment constitutes all of the actions that must be performed to determine the condition of the pipe and to repair it if conditions warrant. This includes conducting internal inspections or hydrostatic tests or implementing other technology that provides an equivalent understanding of the condition of the line (with 90-day advance notification to OPS), and the resulting evaluation, excavation, and repair.

**What must be in the Baseline Assessment Plan?**
The Baseline Assessment Plan must include a written plan for performing the baseline assessments necessary to assure pipeline integrity for each pipeline segment that could impact an HCA. It must include:

- Identification of all the pipeline segments that can affect an HCA
- The integrity assessment method, or methods, planned for use on each identified pipeline segment
- A schedule for assessment of each identified segment
- An explanation of the technical basis for the integrity assessment method(s) selected and the risk factors used in scheduling the assessments.

**Under what conditions should the Baseline Assessment Plan be modified?**
The Baseline Assessment Plan must be modified whenever new HCAs are identified (expected to be every five years and as identified by the operator). Pipeline that can affect newly-identified HCAs must be reflected in the Baseline Assessment Plan within one year after their identification. These pipeline segments must be assessed within five years of their identification. The Baseline Assessment Plan can also be modified if the operator gains knowledge from the initial (baseline) assessments that leads to a change in inspection priorities or other improvements to its program. The operator

must document the modification and the reason for the modification. This documentation must be produced at the time the decision to change is made, not when the change is implemented.

**When must baseline assessments be completed?**
All baseline integrity assessments must be completed by March 31, 2008. Assessments for 50% of the pipeline mileage that can affect HCAs must be completed within September 30, 2004. The highest risk segments should be prioritized for early assessment.

**Can assessments performed before the effective date of the rule be relied on as baseline assessments?**
Integrity assessments conducted after January 1, 1996 can be used as baseline assessments, provided they meet the criteria established by the rule. However, if an operator relies upon an assessment performed prior to March 31, 2001 for purposes of establishing a baseline, that segment must be re-assessed in accordance with the rule's provisions for subsequent assessments. This means that re-inspection of segments for which pre-rule inspections are relied upon must be conducted within five years following the dates those inspections were conducted. This will be in the period during which baseline assessments are being performed. For example, assume a pipeline segment that could affect an HCA was internally inspected in January, 1998, and that inspection met the rule's requirements. If the operator elects to use this inspection as the baseline assessment for a particular segment, then this segment would have to be re-assessed prior to January 2003. At this time the operator will also have to be performing baseline assessments on other pipeline segments.

**What must an operator consider in prioritizing pipe segments for assessment and re-assessment?**
The risk posed by each pipeline segment covered by this rule must be considered in scheduling baseline assessments and periodic re-assessments. In scheduling assessments, an operator must consider all risk factors relevant to that pipeline segment. The rule requires that the following factors be included:

- results of the previous integrity assessment, defect type and size that the assessment method can detect, and defect growth rate
- pipe size, material, manufacturing information, coating type and condition, and seam type;
- leak history, repair history, and cathodic protection history;
- product transported;
- operating stress level;
- existing or projected activities in the area;
- local environmental factors that could affect the pipeline (e.g., corrosivity of soil, subsidence, climatic);
- geo-technical hazards; and
- physical support of the segment such as by a cable suspension bridge.

Additional factors relevant to particular pipelines should also be included. Examples are provided in Appendix C of the rule.

**The rule does not require the Baseline Assessment Plan to be developed until March 31, 2002; however integrity assessments performed since January 1, 1996 can be used to satisfy the baseline integrity assessment requirement. Will operators be penalized for using prior assessments as a baseline assessment if their risk analysis determines that some of these segments may be lower risk than segments which have yet to be assessed?**
The rule requires that operators must conduct baseline assessments on their highest risk line pipe first. Thus, OPS expects that generally the schedule in the Baseline Assessment Plan would show that the highest risk segments are scheduled for assessment prior to the lower risk segments. However, this does not preclude an operator from using a prior assessment for a baseline, even if the segment(s) covered by that assessment later turn out to be relatively lower risk.

**Will operators need to seek waivers from OPS in order to change assessment schedules after the initial Baseline Assessment Plan has been developed?**
OPS understands that there are a number of factors that could result in the need to modify the Baseline Assessment Plans after its initial preparation. For example, as information is obtained from the initial integrity assessments, risk analysis, and operating experience, an operator’s understanding about the specific integrity threats and relative importance of those threats may change. An operator may elect to apply a different integrity assessment method (e.g., select a different in-line inspection tool that may improve the capability to detect a particular type of defect). An operator may also desire to accelerate assessments in some areas because of new information that indicates a higher risk than previously understood. The introduction of new technologies may also result in changes to the Baseline Assessment Plan.
Because assessment plans are likely to change, OPS expects operators to document the basis for changes in the plan so these can be reviewed during inspections. It is not necessary to apply for a waiver to change the Baseline Assessment Plan. Even though an operator's plan may change, the operator must still complete baseline assessments for 50% of the

mileage that can affect HCAs by 9/30/04, and complete baseline assessments for all of the mileage that can affect HCAs by 3/31/08.

**How will OPS view situations where a scheduled baseline assessment for a segment can't be performed in accordance with the schedule due to environmental permitting constraints or city moratoriums on street excavations? These delays cannot always be foreseen five years out. Will operators be allowed to conduct the baseline assessments "out of order" in these cases?**
OPS expects operators to plan sufficiently in advance and to be proactive in terms of permitting, etc., so that assessments can be conducted as planned. OPS recognizes, however, that unexpected situations can arise that may affect the ability to conduct an assessment. Schedule changes due to permitting or local regulations will be reviewed closely to determine if obstacles were truly unexpected or should have been foreseen.

**Should operators archive previous versions of their assessment plans so OPS can track changes to these plans over time?**
OPS expects that changes to the Baseline Assessment Plan will occur as information is gleaned from the initial assessments, the integration of assessment results with other data, and operator risk analyses that utilize this new information. Operators must record and retain the technical basis for changes to their Baseline Assessment Plans. This information must be available for OPS review during inspections. While archiving previous versions of assessment plans is not required, an operator must have adequate documentation to show how the plans have changed and the technical justification for those changes.

**The rule requires that 50% of the line pipe that can affect HCAs be assessed by September 30, 2004 and all of the mileage by March 31, 2008. For purposes of determining the 50% mileage criteria, does an operator use the total mileage that has been and will be assessed, or just the mileage that has been determined as having the ability to impact an HCA? (For example, most operators who use internal inspection, will pig a greater distance than just the portion of the pipeline that can affect an HCA.)**
For purposes of satisfying the mileage requirements, operators must use the cumulative mileage of pipeline segments that can affect an HCA. This includes the miles of pipe that intersect HCAs as well as areas outside those regions where a release could migrate to an HCA. Operators should not use the total miles assessed in making a determination of whether the 50% criteria has been satisfied.

**For purposes of meeting the September 30, 2004 and March 31, 2008 deadlines for completing baseline assessments, is the date of the assessment considered to be the day when the tool run is complete, when the preliminary data is received, or when the evaluation of the in-line inspection results is complete?**
The date on which an assessment is considered complete will be the date on which final field activities related to that assessment are performed, not including repair activities. That will be when a hydrostatic test is completed, when the last in-line inspection tool run of a scheduled series of tool runs is performed, or the date on which "other technology" for which an operator has provided timely notification is conducted. Evaluation of the assessment results, integration of other information, and repair of anomalies must still be performed in accordance with the requirements established for these activities in the rule. These activities are considered to occur after the completion of the "assessment".

**Must all of the highest risk segments be assessed by September 30, 2004, or will OPS allow operators some flexibility to deal with practical issues in scheduling assessments?**
The rule requires that baseline assessments must be completed on at least 50 percent of the line pipe by September 30, 2004, starting with the highest risk pipe. Although, OPS expects operators to concentrate on the highest risk pipe, some segments not among the highest risk pipe may be counted towards the 50 percent requirement. OPS recognizes that practical issues associated with scheduling and conducting assessments may lead to some lower risk pipe being assessed prior to high-risk pipe. For example, during a pig run to address a high risk segment, an operator may also assess another lower risk segment that happen to be located in the same section of pipe that is being inspected. This additional segment may be credited against the September 30, 2004 deadline. OPS inspections will consider how an operator has prioritized segments for assessment to assure that appropriate emphasis is being placed on the highest-risk pipe.

**If an operator develops a single Baseline Assessment Plan that covers both intra- and interstate pipelines, does the need to complete assessments on 50% of the pipeline mileage that can affect HCAs apply to both intra- and interstate line segments, or just interstate line segment mileage? Should the company's Plan identify whether line segments are intra- or interstate?**
The operator may develop a Baseline Assessment Plan as they see fit as long as it meets the requirements of the rule. The 50% requirement will apply to all pipeline systems that are covered under the rule - interstate or intrastate.
The company's plan should identify whether the line segment affecting a HCA is intrastate or interstate. Inspection responsibility for intrastate piping may be done by state agencies (if they are party to agreements with OPS). This information in company plans will help to focus inspection activities by states and OPS to appropriate pipe segments.

**What specific information from the company's baseline assessment plan does OPS expect to retain in its inspection files? For example, will OPS retain the boundaries of segments that could affect HCAs, the assessment methods for these segments, the dates on which these segments will be assessed, etc.?**
To improve the ability to monitor operator implementation of their assessment program, and more efficiently prepare for future inspections, OPS may record basic information on operator integrity assessment plans, including:

- the location of segments that can impact HCAs,
- the assessment methods to be used for those segments, and
- the schedule for conducting these assessments.

Once baseline assessments have been conducted, OPS may also record general information about the condition of the segment and actions taken to mitigate anomalies, as well as schedules for subsequent assessments. This information will be retained in OPS's internal inspection records.

**If an operator has multiple pipeline systems and/or multiple business units, does OPS require the operator to produce a single Baseline Assessment Plan for the entire company, or can an operator create multiple plans to align with its operating units and internal management practices?**
Operators have the flexibility to prepare Baseline Assessment Plans to support their internal management processes and organization structure. Thus, an operator with multiple pipeline systems could have one plan for each pipeline system, one plan for each business unit (or operating entity within the company), or a single plan covering all pipeline systems it operates. Each Baseline Assessment Plan must meet the requirements of 195.452 (c) and address all pipeline segments that can affect HCAs for the pipeline system(s) covered by the Plan.

## Integrity Assessment Intervals

**How often must periodic integrity assessments be performed on pipeline segments that can affect an HCA after the baseline assessment is completed?**
Assessments must be performed at intervals determined by the operator based on segment-specific risk factors but not to exceed 5 years unless an operator has sound technical justification for a longer interval and notifies OPS of its intent to use the longer period.

**Must operators conduct re-assessments before they have completed all baseline assessments?**
All baseline assessments must be completed by March 31, 2008, seven years after the effective date of the rule. Re-assessments for each segment that can affect a high consequence area must be performed within five years after the baseline assessment for that segment is completed (or less if the operator's risk evaluation determines that a shorter interval is needed to assure pipeline integrity). Thus, some re-assessments are likely to be required before all baseline assessments are completed if operators use the entire allowed period (i.e., until March 2008) to perform baseline assessments.
For example, a pipeline segment that can affect an HCA that is assessed (baseline) in 2002 will require re-assessment no later than 2007.

**Can a re-assessment interval be extended beyond 5 years?**
Re-inspection intervals can be extended if a sound technical evaluation and other external monitoring activities show the pipe to be in good condition and provide an equivalent level of understanding of pipe condition as internal inspection or pressure testing. Re-assessment intervals can also be extended if the integrity assessment technology most appropriate to examination of a specific pipe segment is not available. Operators must inform OPS whenever re-inspections are scheduled at longer intervals than 5 years.

**What is the mechanism for requesting adjustments to assessment intervals? Must operators apply for such adjustments?**
The rule requires that operators conduct periodic integrity assessments on all segments of pipe that can affect HCAs at intervals not to exceed 5 years. Thus an operator does not need to inform OPS if it changes the interval between inspections so long as that interval does not exceed 5 years. If the operator desires to use an interval in excess of 5 years, then the operator must notify OPS in accordance with 195.452 (j) (4). The rule provides for intervals in excess of 5 years under two circumstances:

1) if a reliable engineering analysis in conjunction with other technologies provide confidence the pipe is in good condition, or
2) if an integrity assessment device is temporarily unavailable.

In both instances the operator must notify OPS stating their intention to extend the assessment interval and provide a justification for this extension.

**Can the operator use risk assessment data to defend longer intervals between in-line inspections?**
The fundamental purpose of the rule is to improve protection in high consequence areas. Therefore, OPS expects strong risk-based arguments to be a primary focus in the technical justifications to use inspection intervals longer than 5 years.

**What would OPS view as acceptable criteria for assessment intervals longer than 5 years?**
OPS has not yet established criteria for determining whether assessment intervals of longer than 5 years are acceptable. OPS intends to develop criteria at a later date, taking into account information learned during the initial integrity management inspections.

**The early notice on the natural gas integrity management rules includes a provision for service interruptions as a consideration during scheduling of integrity tests. Is OPS considering/willing to extend the same or similar provisions to hazardous liquids operators? How would such considerations be handled?**
OPS understands that practical considerations such as customer demands and meeting community energy needs will influence the scheduling of integrity assessments. Nevertheless, OPS expects operators to schedule and perform baseline and subsequent integrity assessments within the time frames required by the rule for all segments that can impact HCAs. Operators who believe consequences of interrupting service are so severe that baseline assessments for those segments can not be completed by March 31, 2008, or that periodic assessments can not be performed within the allowable five year period should apply for a waiver for the affected segments.

**Once baseline assessments are complete, will operators be able to use their continuing evaluation process to identify primary threats and schedule assessments accordingly, even if this means conducting metal loss and deformation inspections on different intervals?**
OPS expects operators to use the results of their risk analysis, which includes integration of prior integrity assessment results, to determine the appropriate interval for conducting future integrity assessments. This is referred to as the "continual process of evaluation" in 195.452 (j). Where internal inspection is the chosen assessment method, completing the re-assessment will require that both a metal loss and deformation tool be run. Either in-line inspection tool can be run more frequently if threats to pipeline integrity indicate that differing frequencies are appropriate. However, both tools must be run within the required re-assessment interval.

## Integrity Assessment Methods

**What are acceptable integrity assessment methods?**
Internal inspection and hydrostatic testing are acceptable methods to assess pipeline integrity. For electric resistance welded (ERW) pipe or lap welded pipe susceptible to longitudinal seam failures, the method selected must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies. Other technologies that an operator can demonstrate provide an equivalent understanding of pipe condition can be acceptable methods, but operators must inform OPS 90 days before conducting assessment using other technologies.

**Are there different requirements for inspection of pipelines carrying highly volatile liquids?**
The requirements applicable to these kinds of pipelines are no different than those that apply to other hazardous liquid pipelines. Those requirements include the need to consider risk factors applicable to specific pipeline segments. Pipelines such as these can involve unique risk factors, and the rule requires that these be considered in scheduling integrity assessments and considering the need for additional preventive and mitigative actions.

**Are there different requirements for inspection of overhead suspension pipeline bridges?**
The requirements applicable to these kinds of pipelines are no different than those that apply to other hazardous liquid pipelines. Those requirements include the need to consider risk factors applicable to specific pipeline segments. Overhead suspension pipeline bridges can involve unique risk factors, and the rule requires that these be considered in scheduling integrity assessments.

**What kind of tool can an operator use to conduct integrity assessments by internal inspection?**
The rule does not limit the type of tool or tools that can be used for internal inspection. Any tool used must be able to detect corrosion and deformation anomalies, including dents, gouges, and grooves. OPS expects operators to evaluate the segment specific risks associated with each portion of the line that could affect an HCA and determine the appropriate assessment technology or combination of technologies to confirm whether or not those specific threats are present. For electric resistance welded (ERW) pipe or lap welded pipe susceptible to longitudinal seam failures, the tool must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

**What type of pressure test can be used to assess pipeline integrity?**
The rule requires that pressure tests be conducted according to the requirements of 49 CFR Part 195, Subpart E. Operators choosing to assess by pressure test should also assure their corrosion control program is effective. OPS inspectors will pay particular attention to the adequacy of corrosion control programs for pipelines for which pressure testing is used.

**If an operator elects to use in-line inspection for satisfying its baseline assessment requirements, must a metal loss “smart” pig and a deformation tool both be run? If so, must these both be run at the same time, or can these runs be made at significantly different times?**
Given the capabilities of current technology, an operator who elects to use in-line inspection will need to run two tools - a metal loss tool and a deformation device - to satisfy the baseline assessment requirements of 195.452 (c) (1) (i). In most cases, OPS expects that these two tools should be run in a similar time frame to maximize the value of data integration. Furthermore, running the tools in close proximity allows the operator to readily identify potentially serious anomalies such as dents and metal loss.

**Can internal inspection be performed using only a deformation tool if the analysis of the pipeline demonstrates that corrosion is not a primary integrity threat for a specific pipeline segment?**
No. The rule requires that internal inspection be performed with a tool or tools capable of detecting corrosion and deformation anomalies. However, after conducting the baseline assessment, it is possible that an operator might determine that the interval between metal loss tool runs could be extended beyond the five year re-assessment interval if the assessment results review, data integration, and risk analysis demonstrates the line to be in good condition and corrosion is not a significant threat. In this case the operator would have to notify OPS of its intent to use an extended interval between metal loss tool runs, provide the technical basis for this determination, and describe the external monitoring activities that are in place to assure the pipe remains in good condition. OPS will review this notification, considering the unique circumstances of the line segment in question, and notify the operator if the extended interval is acceptable.

**Will OPS establish criteria for minimum acceptable in-line inspection tool capability? (E.g., are low resolution magnetic flux leakage tools acceptable or must high resolution tools be used?)**
OPS expects operators to select the integrity assessment method(s) that provide confidence the location-specific integrity concerns of a given pipe segment will be identified if they are present. Initally, OPS does not intend to establish minimum criteria for in-line tools. However, OPS will evaluate the operator's technical basis for selecting a method for integrity assessment. The in-line tool selection process should consider factors such as a tool's detection capabilities and limitations, the accuracy with which it can locate and size anomalies, and the confidence associated with the tool's measurements. As OPS acquires more understanding of operator integrity management programs and practices as well as in-line tool capabilities, more definitive criteria may be established.

**For operators having line pipe in states that have a pressure testing requirement, will satisfying the state requirement also suffice for satisfying the integrity assessment requirement of the integrity management rule?**
Any pressure test which meets or exceeds the requirements of Subpart E will satisfy the integrity management rule. If a state’s requirements are less (e.g., a shorter “hold” time), then the pressure test required by the state's regulation would not be satisfactory for compliance with 195.452 (c) (1) (i).

**What are the acceptable integrity assessment methods for ERW pipe or lap welded pipe susceptible to seam failure?**
For ERW pipe or lap welded pipe susceptible to seam failures, an operator must:

1) run an in-line inspection device(s) capable of detecting seam flaws, metal loss corrosion, and deformation anomalies, OR
2) perform a Subpart E hydrostatic test.

In addition, as part of an effective integrity management program, OPS expects operators to determine and apply the most appropriate integrity assessment method or methods to address the specific integrity concerns of each pipe segment that can affect an HCA. OPS will review operator integrity management programs to be sure they select the most appropriate method(s) for addressing the integrity concerns of ERW and lap welded pipe. Thus, if seam issues are a particular concern, OPS believes operators electing pressure testing as an integrity assessment method should consider the value of supplementing a subpart E test with a spike test.

**What types of other technology can be used for integrity assessments other than internal inspection or pressure tests?**
An assessment method other than internal inspection or pressure test is referred to in the rule as 'other technology'. The rule does not limit what this technology can be. It must provide an equivalent understanding of the line pipe condition. It could be technology that has not yet been developed, but which may later be demonstrated to have such capability. It

could also be existing technology that might be modified for use in pipeline assessment. An operator must inform OPS 90 days prior to its use.

**How does OPS intend to evaluate an operator's notification to use "other assessment methods", as allowed by 195.452 (c) (1) (i) (C)?**
OPS will evaluate the technical merit of operator notifications reporting an intent to use assessment methods other than those specified in the rule. OPS will inform operators if its evaluation determines that the proposed technique is not sufficiently justified for use. OPS expects to see very complete and compelling justifications for using other methods. OPS recognizes that use of new technologies to conduct inspections is an appropriate part of developing new tools and expanding the state of the art. Nevertheless, OPS considers integrity assessments conducted under this rule to be important to assuring pipeline safety. The operator's technical justification will be key to demonstrating that the proposed technique, although perhaps with limited operational experience, can be expected to provide results with sufficient accuracy and reliability to assure the underlying purpose of the rule. OPS will use third party expertise when required.

**How will OPS communicate information on "other acceptable technologies" [see 195.452 (c) (1) (i) (C)] to industry?**
OPS intends to conduct workshops, use its web site, and sponsor other forums where information on new assessment technologies will be shared. In addition, if an OPS accepts an "other technology" following a review of an operator's notification [per 195.452 (c) (1) (i) (C)], OPS is considering posting its acceptance decision of the notification on the web.

**Is the "spike" hydrostatic test an acceptable integrity assessment method, or must all hydrostatic testing conform with the requirements of subpart E?**
The rule requires that assessments be conducted using internal inspection (pigging), hydrostatic testing conforming to Subpart E, or "other technology" that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. Unless it is performed in addition to pigging or a Subpart E hydrotest, the use of a spike test to identify seam flaws would be considered an "Other technology" under 195.452 (c) (1) (i) (C).
Operators desiring to use the spike test without conducting one of the specified assessment techniques must notify OPS as required by the rule, describe the test procedure to be used, and provide a technical justification for the selection of this methodology. OPS will review the proposed approach and inform the operator if the approach is satisfactory. Operators who perform a spike test in conjunction with a Subpart E hydrostatic test do not need to notify OPS in advance.
When the API standard on pressure testing is revised, OPS will review it and consider whether modifications to the definition of acceptable integrity assessment methods are warranted.

**Will OPS allow liquid operators to use the Direct Assessment process being developed by the gas industry as an acceptable "other technology" for integrity assessment [see 195.452 (c) (i) (C)]?**
OPS believes that the specific techniques (DCVG, C-Scan, Pipeline Current Mapper, etc.) identified in the Direct Assessment approach can be valuable diagnostic tools and would be appropriate for consideration as part of a comprehensive integrity management program by any operator. However, OPS has not yet defined how the Direct Assessment methodology must be applied to provide an "equivalent understanding of the condition of line pipe" as required by 195.452 (c) (1) (i) (C). Thus, at the present time, any operator who desires to use this methodology instead of in-line inspection or pressure testing for conducting a baseline assessment must send OPS a notification of their intent including the technical basis for why the approach provides an equivalent understanding of the pipe's condition [per 195.452 (c) (1) (i) (C)].

**How long should baseline assessment records be retained by the operator?**
Records of anomalies identified during assessments and the actions taken in response to those anomalies must be kept for the life of the pipeline system. OPS expects operators to retain documentation that supports their decisions regarding baseline assessments and subsequent assessments. This would generally include previous assessment plans.

## Anomaly Repair and Excavation

**What constitutes 'discovery of a condition'?**

Discovery of a condition occurs when an operator has adequate information about the condition to determine that it presents a potential threat to the integrity of the pipeline. Depending on circumstances, an operator may have adequate information when the operator receives the preliminary internal inspection report, gathers and integrates information from other inspections or the periodic evaluation, or when an operator receives the final internal inspection report. Operators are required to obtain sufficient information about a condition to make this determination no later than 180 days after an integrity assessment, unless the operator can demonstrate that the 180-day period is impracticable.

**If the segment that can impact an HCA is relatively short (e.g., only 2 miles in length), yet the operator internally inspects a longer portion around this segment (e.g., 50 miles from pig launcher to receiver), do the repair schedules in 195.452 (h) apply to the segment that can impact the HCA or the entire distance over which the pig is run?**
The repair schedules in 195.452 (h) apply only to the segment that can impact the HCA. However, the operator is responsible for promptly addressing serious anomalies or defects identified in the other portions of the pigged section in accordance with 195.401 (b).

## IM Programs and Frameworks

**What factors should drive Integrity Management Program changes?**
An Integrity Management Program should change as appropriate to reflect operating experience, the conclusions drawn from integrity assessments made under the program, other maintenance and surveillance information, and evaluations of the consequences of a failure on the HCA.

**When must the Baseline Assessment Plan and Framework be completed?**
The Baseline Assessment Plan and the Framework both must be prepared by March 31, 2002.

**Will OPS prepare templates for Baseline Assessment Plans or Integrity Management Program Frameworks that operators can use?**
Because of the significant diversity in operator integrity management programs and processes, OPS does not believe it is possible to develop a useful template that is broadly applicable across the industry. As long as the basic requirements for these documents as specified in 49 CFR 195.452 are clearly and completely addressed, an operator is free to use a format for these documents that best supports its internal management and operational needs.

**What is the difference between an acceptable Integrity Management Framework (which must be prepared by March 31, 2002) and a fully developed Integrity Management Program?**
The new integrity management rule (195.452) requires operators to develop and implement an Integrity Management Program. The Integrity Management Program Framework lays the foundation for how the operator intends to develop and implement its program. As described in 195.452 (f), the elements of an integrity management program must include several management, analytical, and operational processes. OPS expects that a number of operators may not have fully developed these aspects of their integrity management programs at this time. OPS also recognizes that making significant, fundamental changes in operator management, analytical, and operational processes and implementing new analytical tools takes time. As such, OPS does not expect operators to have fully developed integrity management programs by 3/31/02.
In the integrity management framework, OPS expects operators to describe how they currently address each element of an integrity management program [195.452 (f)], and their plans for how they intend to improve these processes to reach a fully developed integrity management program. Hence, the framework is a roadmap for developing a full integrity management program. A fully developed integrity management program would include complete, well-documented, and effectively implemented processes for all integrity management program elements defined in 195.452 (f). During OPS inspections, each operator's performance in implementing its framework will be examined.

**What is a framework?**
In the integrity management framework, OPS expects operators to describe how they currently address each element of an integrity management program [195.452 (f)], and their plans for how they intend to improve these processes to reach a fully developed integrity management program. Hence, the framework is a roadmap for developing a full integrity management program. A fully developed integrity management program would include complete, well-documented, and effectively implemented processes for all integrity management program elements defined in 195.452 (f) - e.g., data integration and integrity assessment results review, risk analysis, risk-based decision making, and performance evaluation. During OPS inspections, operator performance in implementing their framework will be examined.

**What is an Integrity Management Program?**
An Integrity Management Program begins with a written framework describing how the elements which follow will be included. Elements required to be part of the program (and the paragraphs of the rule in which they are described) are:

1. a process for identifying which pipeline segments could affect a high consequence area (paragraph (f)(1));
2. a baseline assessment plan meeting the requirements of paragraph (c) of the rule (paragraph (f)(2));
3. an analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (paragraph (g) of the rule);
4. criteria for repair actions to address integrity issues raised by the assessment methods and information analysis (paragraph (h));
5. a continual process of assessment and evaluation to maintain the integrity of a pipeline (paragraph (j));

6. identification of preventive and mitigative measures to protect the high consequence area (paragraph (I));
7. methods to measure the effectiveness of the program (paragraph (k));
8. a process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (paragraph (h)(2)).

A listing of the segments identified by the process described in (1) above must be part of the baseline assessment plan (item 2) and is also considered part of the integrity management program.

**Will an operator be allowed to have one integrity management program that includes all of its regulated pipelines, in addition to those that can affect HCAs?**

Yes. Most of the elements of an integrity management program (e.g., the risk analysis process and the review of integrity assessment results) can and should be applied to the entire pipeline system. However, in documenting the program results, those actions specific to segments that can affect HCAs and thus subject to the provisions of 195.452 (e.g., the integrity assessment results, pipeline repairs to address integrity issues, the leak detection system and EFRD evaluations, etc.), should be clearly discernable and readily available for OPS during inspections.

**Can operators include rural gathering systems in integrity management plans and programs? If so, will OPS inspect these portions of their plans and programs?**

Operators can include rural gathering systems in their integrity management program if desired. However, at this time, the provisions of 195.452 do not apply to rural, low stress pipelines, and OPS will not inspect for compliance on these lines.

**Does OPS expect operators to apply different relative risk ranking systems for lines in HCAs?**

An operator must have a process that considers all factors that affect the likelihood and consequences of pipeline failure and produces a relative risk ranking of pipeline segments that can affect HCAs. This same process can also be applied to other pipeline segments outside of HCAs. However, when conducting integrity management inspections, OPS expects to review a relative risk ranking of all segments that can affect HCAs as part of the Baseline Assessment Plan review.

**What integrity management program documentation should be available for OPS inspections and how long should that integrity management-related documentation be retained?**

Appendix C, paragraph VI provides an extensive listing of records that should be kept, and documentation that should be developed and maintained for an integrity management program. In addition to these items, each operator may have documentation that is unique to its integrity management program operation or program results. Records associated with integrity management program activities such as internal inspection results, pipe repair and mitigation records, risk analysis results, and records associated with the implementation of other preventive and mitigative actions such as EFRDs should be retained for the life of the pipeline system. The technical justification for changes to the Baseline Assessment Plans, the use of other technologies, and the extension for integrity assessment intervals beyond 5 years should also be retained for the life of the system. Documentation of integrity management program operational, analytical, and management processes should be kept up-to-date to reflect current practices and insights obtained from the integrity management program results.

**What is a continuous process of evaluation and assessment?**

After completing the baseline integrity assessment, an operator must periodically assess pipe segments that could affect high consequence areas, and evaluate the integrity of those portions of its system. An operator must base the assessment and evaluation frequency on risk factors specific to its pipeline, including at least the factors specified for consideration in scheduling assessments. The evaluation must consider the past and present integrity assessment results, risk analysis results, and decisions about repair, and preventive and mitigative actions taken to reduce risk.

**What kinds of information must be integrated in performing a continual evaluation of pipeline integrity?**

An operator must consider all information relevant to determining risk associated with pipeline operation that could affect HCAs. This means information regarding the likelihood that a pipeline leak or failure will occur, as well as information regarding the consequences to an HCA. A list of some of the more important information that should be considered in an integrated manner is provided below.

- Results of previous integrity assessments
- Information related to determining the potential for, and preventing, damage due to excavation, including damage prevention activities, and development or planned development along the pipeline
- Corrosion control information (e.g., test station readings, close interval survey results)
- Information about the pipe design and construction (e.g., seam type, coating type and condition, wall thickness)
- Operating parameters (e.g., maximum operating pressure, pressure cycle history)
- Leak and incident history
- Information about how a failure could affect a high consequence area, such as the location of a water intake

**How is an operator to monitor the effectiveness of its integrity management program?**
The rule requires that an operator's program must include methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas [195.452(k)]. OPS expects that integrity management programs will evolve and improve as experience is gained, and measurement of whether the program is effective is important in guiding that evolution. Operators should periodically evaluate the effectiveness of their integrity management program. This evaluation process should include reviewing:

- The integrity assessment methods and practices being used. (e.g., Are the in-line inspection tools delivering the quality of information expected?)
- The management and analytical processes. (e.g., Is the risk assessment process failing to identify problem areas on the line?)
- Root cause analysis of failures and near-misses. Are these occurrences being critically examined and are the lessons learned being implemented?
- Performance measures. Are objective measures of program results showing that improvement is needed?

Appendix C includes guidance on methods that can be used to evaluate a program's effectiveness.

**Will operators be expected to consider external conditions such as earthquake fault lines or mining subsidence in their integrity management program? Will these be classified as HCAs or require special repair provisions?**
As part of the information and risk analysis required by 195.452 (f) (3) and 195.452 (i), an operator is expected to consider all information that can affect the likelihood and consequences of pipeline failure. 195.452 (e) (1) specifically identifies geological hazards and subsidence as risk factors to consider in prioritizing segments for integrity assessment scheduling. Thus, if such external risk factors are present, they must be considered by the operator. These external conditions are not HCAs. HCAs are specifically defined in 195.450 to include high population areas, other populated areas, commercially navigable water ways, and unusually sensitive areas. It is possible that geological hazards may be present in HCAs, but a region near the line that contains geological hazards is not (by itself) an HCA. The repair provisions of 195.452 (h) apply only to line segments in HCAs - not segments in geological hazard areas outside of HCAs. However, the presence of geological hazards or other external factors near line segments that can affect HCAs should be considered when establishing the schedule for anomaly mitigation and repair required by 195.452 (h) (4).

**The Integrity Management Program portion of the rule [195.452 (f)] applies to all portions of a pipeline system that can impact HCAs, including pump stations, terminals, and other equipment. What must an operator do to comply with the rule for these facilities?**
While the integrity assessment provisions of the rule apply only to the line pipe, the other provisions of the rule apply to pump stations, terminals, and other equipment if a failure at these locations could impact a high consequence area. Thus, operators should include in their integrity management program processes for addressing these facilities. These processes should:

- identify if failures at these facilities could impact HCAs,
- integrate all available information affecting the likelihood and the consequences of equipment or facility failure, and
- identify and implement additional preventive or mitigative measures to reduce risk at these facilities, if needed.

An operator's performance monitoring process should evaluate the effectiveness of these processes and the risk controls that are implemented to reduce facility risk.

**The rule requires that the review of integrity assessment results and information analysis (i.e., risk analysis) be performed by a person qualified to evaluate the results and information. Are these covered tasks under the new Operator Qualification requirements? If not, how are operators expected to demonstrate that they have satisfied this requirement?**
The integrity assessment results review and risk analysis are not "covered tasks" under Subpart G of 195. During OPS inspections, operators should be prepared to describe the relevant experience, training and other qualifications of the personnel performing this work. As part of their Integrity Management Program Framework, they should also describe their plans to assure that individuals performing this work have the necessary technical expertise and experience. During subsequent inspections, operator progress against these plans will be reviewed.

## Leak Detection, EFRD, and Additional Risk Controls

**What is an emergency flow restricting device (EFRD)?**
A device that can limit the amount of product released as a result of a leak or rupture. An EFRD is defined by the rule as either a check valve or a remotely operated valve.

**What criteria must an operator use in determining whether emergency flow restricting devices are required to protect HCAs?**
Operators must make these determinations using criteria that they define, considering the circumstances of each HCA and the pipeline segments that may affect it. The rule includes specified factors that must be considered in these evaluations. They include:

- the swiftness of leak detection and pipeline shutdown capabilities,
- the type of commodity carried,
- the rate of potential leakage,
- the volume that can be released,
- topography or pipeline profile,
- the potential for ignition,
- proximity to power sources,
- location of nearest response personnel,
- specific terrain between the pipeline and the high consequence area, and
- benefits expected by reducing the spill size.

An operator is required to install an emergency flow restricting device if the operator determines one is needed to protect an HCA. OPS inspectors will review operator determinations.

**What criteria will OPS use to determine whether an operator's evaluation of the need for EFRDs is satisfactory?**
The operator's determination of whether or not to install EFRDs to protect a particular HCA or group of HCAs should result from a site-specific risk analysis. The rule requires [195.452 (i) (4)] that such an analysis consider at least the time required to detect leaks, the time required to shutdown the system and isolate the break, the type of commodity in the pipeline, the range of potential leak rates and volumes that could be released, the topography or pipeline profile, the potential for ignition, the proximity to power sources, the location of the nearest response personnel, the terrain between the pipeline segment and the HCA, and the expected benefits that can be achieved by installing an EFRD. OPS will be reviewing operator analyses for thoroughness, but has not developed specific acceptance criteria.

**What criteria must an operator consider in determining whether enhancements to leak detection are required?**
Operators are required to have a means of detecting leakage on their pipelines. Operators must evaluate that capability and improve it, if necessary, to protect the high consequence area. The evaluation must include at least the following factors: length and size of the pipeline, type of product carried, the pipeline's proximity to the high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results. In addition, OPS believes the operator should consider:

1. The system operating characteristics (e.g., steady state operation, high transient pressure and flow),
2. Current leak detection method for the HCA areas,
3. Use of SCADA,
4. Thresholds for leak detection,
5. Flow and pressure measurement,
6. Specific procedures for lines that are idle but still under pressure,
7. Specific consequences related to sole source water supplies regarding additional leak detection means,
8. Testing of leak detection means, such as physical removal of product from the pipeline to test the detection, and
9. Any other characteristics that are part of the system leak detection.

**What is the minimum acceptable leak detection system in order to comply with 195.452 (i) (3), which states "an operator must have a means to detect leaks on its pipeline system"?**
OPS will address leak detection capability with each operator according to the requirements of the regulation. This includes a "means to detect leaks" and an evaluation of the capability of the leak detection means. The rule specifies several factors that the evaluation must consider. These, and additional factors that OPS believes the operator should consider are:

- the length and size of the pipeline,
- type of product,
- proximity to the HCA,
- the swiftness of leak detection and the time to isolate the leak,
- location of nearest response personnel,
- leak history, and risk assessment results
- the system operating characteristics (e.g.,steady state operation, highly transient pressure and flow),
- current leak detection method for the HCA areas,
- use of SCADA,
- thresholds for leak detection,
- flow and pressure measurement,
- specific procedures for lines that are idle but still under pressure,
- specific consequences related to sole source water supplies regarding additional leak detection means,

- testing of leak detection means such as physical removal of product from the pipeline to test the detection, and
- any other characteristics which are part of the system leak detection.

OPS will use this information to support an assessment of the adequacy of the operator's leak detection. OPS intends to develop a set of leak detection characteristics to expedite the adequacy assessment in the future.

**49 CFR 195.134 and 195.444 require that computational pipeline monitoring (CPM) leak-detection systems on hazardous liquid pipelines must comply with API Standard 1130 for design and operations/maintenance respectively. Paragraph (i) (3) of the integrity management rule requires that operators must have a means to detect leaks on pipelines that can affect HCAs. Must leak detection means used to satisfy 49 CFR 195.452 (i) (3) meet API-1130?**

There are many ways that an operator may detect leaks. The operator must conduct a risk analysis, per 195.452 (i) (2) to identify the need for additional preventive and mitigative features. Leak detection capability must be evaluated, per 195.452 (i) (3), using the results of this risk analysis and other factors listed in that paragraph. An operator must determine if modifications to its leak detection means are needed to improve the operator's ability to respond to a pipeline failure and protect HCAs. An operator may determine, on an individual pipeline segment basis, that a CPM system is needed to meet this need. If a CPM system is employed, its implementation and operation must satisfy the requirements of 195.134/444, which reference certain aspects of API-1130.

**What preventive and mitigative actions must be taken to protect HCAs?**

Operators must conduct risk analyses for the line segments that could affect HCAs. These analyses should identify and evaluate the need for additional preventive and mitigative actions to protect HCAs. The rule does not specify which actions must be taken. A list of some measures which might be taken includes:

- implementing damage prevention best practices,
- enhanced cathodic protection monitoring,
- reduced inspection intervals,
- enhanced training,
- installing EFRDs,
- modifying the systems that monitor pressure and detect leaks,
- conducting drills with local emergency responders, and
- other management controls

An operator must implement the appropriate preventive and mitigative actions to address the risks unique to each specific segment.

**What factors must be considered in risk analyses conducted to determine if additional preventive or mitigative actions are needed?**

An operator must consider all risk factors relevant to a particular pipeline segment. This includes risk factors that influence both the likelihood and the consequences of pipeline failure. Thus would include design and construction information, maintenance and surveillance activities, operating parameters and operating history, right-of-way information, information about the population and the environment near the pipeline, etc. The rule specifically identifies several risk factors that should be considered including:

- terrain surrounding the pipeline segment, including drainage systems such as small streams and other smaller waterways that could act as a conduit to the high consequence area;
- elevation profile;
- characteristics of the product transported;
- amount of product that could be released;
- possibility of a spillage in a farm field following the drain tile into a waterway;
- ditches along side a roadway the pipeline crosses;
- physical support of the pipeline segment such as by a cable suspension bridge;
- exposure of the pipeline to operating pressure exceeding established maximum operating pressure.

**How long after completing the baseline assessment for a segment does an operator have to conduct a risk analysis and determine whether additional preventive or mitigative actions are needed (including the need for EFRDs and leak detection system enhancements)? If an operator determines that additional actions are warranted, how long do they have to implement them?**

After an operator completes its baseline assessment for a segment, it should integrate the results of this assessment into its risk assessment process to identify the most significant risks that remain; and then identify actions that can be taken to address the highest risks. Although the rule establishes no firm time limits by when this risk analysis must be performed, OPS believes it is reasonable to expect that this analysis as well as the identification of potential preventive and mitigative actions should be completed within one year after the assessment has been performed. This will allow time for reviewing the assessment results and excavating the worst features, thereby developing confidence in the validity of the assessment.

OPS recognizes that the time required to implement preventive and mitigative actions is highly dependent on the proposed risk control activity.  Some actions may be simple "quick fix" activities that can readily be implemented in the field.  Other actions may involve major capital expenditures and require significant time for budgeting, engineering and design, and implementation.  Because of this wide disparity, there is no fixed time requirement for implementing preventive and mitigative actions.  OPS does expect operators to provide a schedule by when additional preventive and mitigative measures will be taken, and to act as quickly as practical after identifying the need for such risk controls.  In situations where lengthy periods are required for implementation, operators should determine if there are relatively simple, interim measures that can be taken while major projects are being implemented.

**How do operators assess and control risk caused by third-parties over which they have no direct control?**
As part of a comprehensive risk analysis required by 195.452 (f) and 195.452. (i), OPS expects operators to determine the risk associated with third party damage to pipeline segments that could affect an HCA.  OPS will not prescribe specific risk analysis methods that the operator must use; there are a number of acceptable approaches.  OPS also understands that outside force damage prevention is challenging because it involves factors outside of the operator's control.  Nonetheless, there are a number of actions operators can take to reduce the likelihood of third party damage.  If a pipeline segment can affect an HCA, and third party damage is determined to be a significant risk (e.g., as might be expected in a high population area, with new construction near the line), 195.452 (i) (1) requires the operator to take measures that reduce the likelihood of third party damage.

## Inspection and Enforcement

**How will OPS inspect operators for compliance with the new Integrity Management rule?**
The new Integrity Management rule requires operators to identify all pipeline segments that could impact High Consequence Areas (HCAs) by December 31, 2001.  Operators must further have Baseline Assessment Plans delineating how and when the initial integrity assessments will be performed on these segments, and an Integrity Management Framework prepared by March 31, 2002.  The initial phase of company inspections for compliance with these new requirements will be performed in two steps.

- The first step involves an initial inspection of the operator's segment identification process and results, and a completeness check on the content of the company's Baseline Assessment Plan(s) and Integrity Management Framework.
- This step will be followed immediately by more comprehensive examinations of the Baseline Assessment Plans and processes described in the Integrity Management Framework.

OPS believes that these inspections will be separate from the standard compliance inspections for the other requirements of Part 195.
The inspection process will also involve examining operator implementation of their Integrity Management Programs. These inspections would check to see that operators are following their Baseline Assessment Plan and implementing their Integrity Management Framework, including performing the assessments as planned, performing the required repairs, and implementing integrity management process improvements.

**When will these initial integrity management inspections be performed?**
The segment identification and completeness checks will begin in January 2002.  OPS aims to have all operators subject to the new rule inspected in early 2002.  After the segment identification and completeness check inspections have been completed, the more comprehensive inspections of the Baseline Assessment Plans and Framework processes will commence.  OPS currently plans to complete these more detailed inspections within two years.

**What is the expected duration of the segment identification and completeness check inspections?**
For most operators, the segment identification and completeness check inspection is expected to require approximately one day.

**What will the segment identification and completeness check inspection cover?**
A small team of Region inspectors and Program Development personnel will examine:

- The operator's process for identifying which segments can impact an HCA and delineating the segment boundaries.
- The location of the segments on pipeline maps, comparing the operator's segment definition with the information from the National Pipeline Mapping System to confirm no major areas have been overlooked in the segment identification.
- A sample of operator analyses to determine the boundaries of the segments that "can affect" an HCA to confirm appropriate and consistent application of their process and reasonableness of assumptions.
- The Baseline Assessment Plan and IM Framework contents against the minimum requirements delineated in the rule to assure they contain all of the essential elements (i.e., a completeness check)

**Will the Segment Identification and Comprehensive Baseline Assessment Plan and Integrity Management Program inspections be scheduled in advance?**
OPS will schedule all integrity management inspections as far in advance as possible. OPS will coordinate the inspections with the companies to identify mutually agreed upon dates whenever possible.

**When will the inspection protocols be available?**
OPS intends to complete the inspection protocols for the Segment Identification and Completeness Check inspections in December. Protocols for the Comprehensive Baseline Assessment Plan and Integrity Management Program Framework review will be available in the spring, 2002. Similar to the other inspection forms, OPS expects to post these on its web site.

**During Segment Identification and Completeness Check inspections, will OPS provide feedback to the operator on intended plans for "other assessment methods," even if the operator has not yet given OPS a 90-day notification?**
OPS will discuss all aspects of compliance with 195.452 that time allows during these inspections. The purpose of these inspections is to determine whether the operator has identified pipeline segments that could affect an HCA, to discern the operator's general level of understanding of the integrity management program requirements, and to ascertain progress in preparing the Baseline Assessment Plan and Integrity Management Framework. As time permits, OPS will be open to discussing specific issues associated with an operator's integrity management program. However, such a discussion will not relieve the operator from the requirement to notify OPS if it intends to use an "other assessment method" per 195.452 (c) (1) (i) (C).

**When does OPS expect to complete the Comprehensive Baseline Assessment Plan and Integrity Management Program Framework inspections?**
The current plan is to complete these within a two year period with the inspections starting in the spring 2002.

**What are the state pipeline safety agency roles in the integrity management inspection process?**
To the maximum extent practical, OPS will share its inspection documentation with states so that states can provide input to OPS prior to finalizing operator integrity management inspections. For those states that are interstate agents or who have an agreement with OPS to share responsibility for field monitoring, there will be specific written assignments of field duties. In those instances where operators have voluntarily shared integrity plans with states in advance of review, OPS will take into consideration any input states want to provide as part of its review process.

**Will integrity management inspection results on a company be publicly available?**
OPS does not intend to make the detailed results of individual company inspections available to the public. However, consistent with the provisions of the Freedom of Information Act, members of the public may request and be granted access to information from OPS files. OPS is considering making summary level information on the industry's performance available to the general public on its web site. The specific information and measures of performance are under development.

**How will "noteworthy practices" be identified during inspections and communicated to other operators?**
During the review and discussion of an operator's integrity management program, OPS expects to see a number of "noteworthy" practices that may not be well known or implemented throughout the industry. When such practices are identified, OPS will ask the operator if it is acceptable to communicate basic information about the practice to a broader audience, so that others might learn from the experience. The mechanism for communication has not been determined, but OPS is considering periodic workshops and the use of a web site to provide basic information about such practices.

**What kind of compliance and enforcement action can operators expect from the initial segment identification and completeness check inspections?**
Operators that have clearly failed to identify segments, or who have obvious, major omissions from their segment list, will be cited using existing OPS compliance practices. Operators whose segment identification process appears weak, and for which the review raises significant questions, will be provided feedback on areas to consider strengthening in their approach. Compliance action might not be taken in these instances, but would be considered following the subsequent, more comprehensive, inspection of Integrity Management programs, if improvement is not evident.
The completeness check portion of these initial inspections will be handled differently. The purpose of the completeness check is to provide feedback to operators on the completeness of their Baseline Assessment Plans and Integrity Management Program Frameworks, informing them if important elements of these documents appear to be missing. This will provide operators an opportunity to address major omissions before the more comprehensive inspections of these documents are conducted. Because some of these completeness checks will be conducted before March 31, 2002 when the Plans and Frameworks must be completed, compliance action would not be appropriate, and none is anticipated. OPS believes that the completeness checks are important as a means to identify inconsistencies between operator plans and the requirements of the rule early when they can be more easily be corrected.

**How will OPS provide training and oversight to state inspectors conducting reviews and audits of operator integrity management plans? How will OPS ensure consistent enforcement across an operator's system? How will OPS ensure consistent and fair enforcement across the pipeline industry?**

OPS is aware that the review of operator integrity management programs and processes will involve some subjective judgments on the part of the inspection team. OPS intends to exercise care in conducting these inspections to assure consistency and fairness. We will use a core of experienced inspectors on the teams for the Segment Identification and Completeness inspections and for the Comprehensive inspections that will follow. These inspectors will work together to develop criteria and examples to be used in formal training courses for all IM inspectors and subsequently for all inspectors, including State personnel.

**Can an operator be cited for not complying with Appendix C?**

The enforceability of Appendix C is addressed in the preamble to the final rule, as follows:

> "An Appendix is guidance that is intended to give advice to operators on how to implement the requirements of the integrity management rule. An Appendix does not have the same force as the regulation itself. An operator does not have to follow the guidance. However, if an operator incorporates parts of the Appendix into its integrity management program, an operator must then comply with those provisions."

The guidance in Appendix C will also be utilized in developing OPS's inspection protocols and consulted, as appropriate, during the inspection process.

**At a recent conference, OPS indicated that it intended to conduct preliminary reviews of integrity management program documentation. When will such reviews be conducted? Will OPS contact operators? Can operators contact OPS and request such preliminary reviews?**

OPS will visit a number of operators prior to starting the Segment Identification and Completeness inspections to discuss and validate inspection protocols. Companies were chosen based in large part on the experience OPS has in working with them through the Risk Management Demonstration and System Integrity Inspection programs.

## State Roles, Intra-State Lines

**Some States have adopted, or are considering, integrity management rules including requirements similar to those in the federal rule. If a company operates both intra- and interstate pipelines in such a State, which integrity management rules apply to each type of pipeline?**

A state certified to inspect an intrastate pipeline is required to have safety standards that are at least as stringent as the federal pipeline safety rules. If a State rule is less stringent, or has not been adopted as State law, the federal rule would apply to both intrastate and interstate pipelines.

Once a State has adopted integrity management program standards, then those standards, including any provisions that may be more restrictive than the federal rule, would be enforced by the State for intrastate pipelines.

Questions about applicability and enforcement of rules in specific States should be directed to the appropriate State agency.

**If a company operates both intrastate and interstate lines in a State, will both OPS and the State perform similar inspections?**

The State will inspect and enforce for purely intrastate operators. The State may participate with OPS in inspections of interstate operators. Separate inspections covering interstate pipeline operations by the State and OPS are not intended. Some duplication is possible during intrastate pipeline inspections, to the extent that intrastate pipeline operations use the same integrity management plans and procedures as used for interstate.

**Does OPS consider current Texas state rules adequate or will Texas have to adopt the new Federal rule?**

Yes, Texas, like all states in the pipeline safety program, will have to adopt the new federal rule as part of their certification program. The Texas rule addresses pipeline assessment and integrity program management. It's provisions are at least as stringent as those in the federal rule, provided that a maximum five-year re-assessment interval is used for high consequence areas (as defined in 195.450). Texas will rely on the federal rule for requirements for management and repair, leak detection, and emergency flow restriction devices.

**The Federal Rule identifies certain situations where an operator is required to notify OPS:**

1. **if they intend to use an assessment interval greater than 5 years;**
2. **if they desire to use a technology other than in-line inspection or pressure testing to conduct integrity assessments, or**
3. **if the repair provisions in 195.452 (h) (3) can not be met and the operator can not provide safety through a reduction in operating pressure.**

**For intra- and interstate pipelines operating in States with their own integrity management rules, should these notifications be sent to OPS, to the State, or both?**
All notifications required by 195.452 should be submitted to OPS in accordance with the provisions of that rule. OPS will forward notifications affecting intrastate pipelines to the affected State and the appropriate OPS Regions, who will coordinate their reviews as appropriate.
States may establish notification requirements for intrastate pipelines that are more restrictive than the federal requirements. In such cases, operators would also need to comply with the State requirements.

**For those requirements of State integrity management regulation that are less stringent than the Federal rule (e.g., time interval between periodic assessments), will OPS require the state to adopt or revise its rule to incorporate the Federal requirements?**
State requirements must be at least as stringent as corresponding federal requirements. For example, the Texas Railroad Commission will assure that the requirements of the federal rule are being met, as a minimum, during its review of operator assessment plans (as required by the Texas rule). This will include assuring that 5-year re-assessment intervals are used for unusually sensitive areas in rural locations that would otherwise be subject to a 10-year requirement under the Texas rule. The Texas rule applies to more than high consequence areas.

**The Texas rule requires that written plan by February 1, 2002 - two months before the deadline for Baseline Assessment Plan and Integrity Management Framework preparation are required by 195.452. Does the Texas operator have to meet an earlier date if operating in multiple states but trying to develop a single program?**
Yes.

**If an operator develops a single Baseline Assessment Plan that covers both intra- and interstate pipelines, does the need to complete assessments on 50% of the pipeline mileage that can affect HCAs apply to both intra- and interstate line segments, or just interstate line segment mileage? Should the company's Plan identify whether line segments are intra- or interstate?**
The operator may develop a Baseline Assessment Plan as they see fit as long as it meets the requirements of the rule. The 50% requirement will apply to all pipeline systems that are covered under the rule - interstate or intrastate.
The company's plan should identify whether the line segment affecting a HCA is intrastate or interstate. Inspection responsibility for intrastate piping may be done by state agencies (if they are party to agreements with OPS). This information in company plans will help to focus inspection activities by states and OPS to appropriate pipe segments.

**If a state establishes a definition that expands upon the HCAs defined in 195.450, do the requirements of 195.452 apply to line segments that affect these additional state-defined HCAs?**
For both intra- and interstate pipelines, the requirements of 195.452, as a minimum, apply to HCAs as defined in 195.450. States may apply more restrictive requirements, including a broader definition of HCAs to intrastate lines, but those requirements do not affect interstate pipelines. (It should be noted that the Texas rule does not define HCAs. The Texas rule applies to all pipe.)

## Notifications

**Will OPS review these and formally respond to the operator? Will OPS communicate responses to specific company notifications to the broader industry?**
OPS expects to review all notifications received from operators and to respond in a timely manner to those in which it finds the proposed approach unacceptable. A centralized process involving input from the OPS Regions is being developed to assure thorough review. OPS will coordinate review of notifications affecting intrastate pipelines subject to the rule with the States, as appropriate. While the OPS approach for review and processing operator notifications is still under development, the current plan includes posting company notifications and OPS responses to those notifications on the web. This will allow other operators to see how OPS has responded to various operator proposals.
Operators subject to specific State rules and regulations that require notification must also comply with those provisions.

**Are there notification requirements applicable to the use of 'other technology'?**
Yes. Operators planning to use technology other than internal inspection or pressure testing to assess pipe integrity must notify OPS no less than 90 days prior to the planned assessment. OPS will review the technology for appropriateness. If OPS concludes that use of the technology is not appropriate, it will inform the operator that it cannot be used. In that event, internal inspection or hydrostatic testing will need to be used.

**What must be included in notices informing OPS of inspection intervals that will extend beyond 5 years? When must they be submitted?**
An operator extending an inspection interval beyond 5 years because the selected integrity assessment technology is not available must provide technical justification for why the intended assessment tool is most appropriate and explain why it

cannot be available in time.  The operator must also describe actions it is taking to evaluate the integrity of the pipe in the meantime.  Notices of this kind of extension must be submitted to OPS no less than 180 before the end of the 5-year interval.

Operators using an 'engineering basis' to justify a re-assessment interval in excess of five years must provide a description of the technical basis demonstrating sound pipe integrity.  They need not submit detailed engineering evaluations; these evaluations will be examined during OPS inspections.  Operators must submit a notification of this kind of extension no less than 9 months before the end of the 5-year interval.  This will allow time for review and inspection of the technical basis to occur.

In either case, OPS will consider an operator's justification to determine if they agree that it supports a longer inspection interval.  If OPS concludes that a longer interval is not justified, they will inform the operator and a 5-year inspection interval will have to be used.

## NPMS

**How do operators obtain information about the location of high consequence areas now that NPMS information is no longer available on the internet?**
The pipeline and unusually sensitive area data layers are no longer available for download from the NPMS homepage. Operators are able to obtain the data by contacting OPS directly.  Instructions on requesting the information are available on the NPMS data download page.  OPS will only provide back to the operator a copy of their pipeline system and not a copy of the entire pipeline system.

**How is a single line that transports both gas and liquid represented in NPMS?**
The pipeline is classified based on the primary commodity listed in the COMMODITY1 attribute field. If COMMODITY1 is "crude oil", then the pipeline is classified as a hazardous liquid pipeline.

**Is the NPMS collecting gathering and distribution line data?**
No.

**When will OPS require operators who have not supplied their system maps to NPMS to provide this data?**
The NPMS is a voluntary initiative and does not currently have a requirement for pipeline operator participation.

**With regard to NPMS drinking water data, all of the sources appear to be the same size - where does the data come from? How was the diameter/buffer from intakes determined?**
Most of the drinking water data comes from state drinking water agencies and the Environmental Protection Agency.  The drinking water USAs that are surface water intakes have a five mile buffer placed around their location.  The ground water USAs have buffers that vary in size.  These buffers are designated by the state's source water protection program or their wellhead protection program and these buffer sizes vary from state to state.

**Operators were required to provide NPMS information on the confidence/accuracy of their pipeline location information. Is a similar accuracy available for the other data layers?**
Yes.  Metadata is associated with the commercially navigable and high population/other populated areas data layers in NPMS.  The metadata describes the sources and accuracies of the data layers.  Metadata is being developed to provide information on the data used to create the USAs.

**When USA information for a given state is posted on NPMS, will it be for the entire state, or will the data be posted piecemeal over time?**
Ecological USAs and drinking water USAs will be posted for the entire state and will not be posted piecemeal.  For most states, the ecological USAs will be available prior to the drinking water USAs.

## Miscellaneous

**What are recognized industry practices?**
Recognized industry practices include those found in national consensus standards or reference guides.

**When can an operator use an alternative to a recognized industry practice?**
An operator may elect to use an alternative to a recognized industry practice for any of several reasons.  For example, an alternative practice could utilize new technology, such as a new generation of internal inspection device that has improved detection capabilities.  An alternative technology could also be one that has been successfully used in other countries or by other pipeline companies but has not yet been codified into a national consensus standard.  OPS wants to encourage operators to use innovative practices that are based on sound engineering judgment.  Use of such alternatives helps

ensure that the state-of-the-art in pipeline safety technology will be improved. The rule requires that the selection of an alternative must be based on a reliable engineering evaluation. Use of an alternative must provide an equivalent (or better). An operator must document its use of an alternative practice when the operator makes the decision to use the alternative.

**What is DOT's purpose for creating an Appendix C rather than placing this material in the regulation?**
Appendix C was created to provide additional guidance and clarification for selected requirements in the rule. This was provided to assist operators in understanding the basic rule requirements and what might be necessary for compliance. Because the information in Appendix C is guidance, rather than mandatory requirements, it was determined that an Appendix was the appropriate location for this material.

**API-1160 will be issued shortly. What process will OPS use to determine whether to adopt or reference portions or all of this standard in 195? Does OPS intend to reference API-1160, or replace Appendix C with API-1160? On what time frame can the industry expect this decision to be made?**
After the API Integrity Management Standard has been officially published, OPS will consider whether or not to adopt all or part of this Standard. Public comment will be solicited as input to this decision process. OPS is currently focused on issuing a final integrity management rule for the remaining hazardous liquid pipeline operators, as well as integrity management requirements for natural gas operators. These are among the highest priorities on the OPS regulatory agenda. OPS will work as quickly as possible to consider the adoption of API-1160, consistent with the need to complete these high priority initiatives.